Power-frequency control of hydropower plants with long penstocks in isolated systems with wind generation

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A B S T R A C T

In this paper the power-frequency control of hydropower plants with long penstocks is addressed. In such configuration the effects of pressure waves cannot be neglected and therefore commonly used criteria for adjustment of PID governors would not be appropriate. A second-order Π model of the turbine-penstock based on a lumped parameter approach is considered. A correction factor is introduced in order to approximate the model frequency response to the continuous case in the frequency interval of interest. Using this model, several criteria are analysed for adjusting the PI governor of a hydropower plant operating in an isolated system. Practical criteria for adjusting the PI governor are given. The results are applied to a real case of a small island where the objective is to achieve a generation 100% renewable (wind and hydro). Frequency control is supposed to be provided exclusively by the hydropower plant. It is verified that the usual criterion for tuning the PI controller of isolated hydro plants gives poor results. However, with the new proposed adjustment, the time response is considerably improved.

1. Introduction

In last years, the use of renewable energy sources to displace fossil fuels in small isolated systems has received considerable attention [1–4]. Many islands have an excellent local wind potential so that economic and environmental costs of fuels may be avoided. Although these sources can contribute to some extent to power-frequency regulation, in many cases this service is provided mainly by conventional power plants. Hydropower plants can assume advantageously this task due to its renewable character. Moreover pumped storage schemes compensate uncertainty in wind production. This type of solution is usually named "combined wind-hydro generation".

The use of PID governors in hydropower plants is a common practice [5] and suitable criteria for gain adjustment have been thoroughly studied in last decades [6–11]. However the hydropower plant configurations found in the systems mentioned above may include substantial differences with respect to general cases. Specifically, the length of the penstock can be considerably large due to special topographic conditions. This circumstance limits the applicability of the rigid-water-column models [12] and the PID adjustment criteria based on this assumption [13,14].

Although several contributions have been described to modelling the dynamic response of hydropower plants, when the influence of pressure waves cannot be neglected [15–19] very few attempts have been found in the literature dealing with the adjustment of gains of the PID governor in such cases. It is worth mentioning the work presented in Ref. [20] where the stability boundaries in terms of the PI gains are determined under the influence of the water column elasticity, extending the results obtained for rigid water column. In Ref. [21] a methodology based on a reference model is proposed to obtain a PID governor gains; the turbine-penstock is represented by a synthesized second order model [13]. In Ref. [17] the PID parameters determination is based on a high order plant model, where the turbine transfer function is identified by means of time-domain simulations.

The work of [8,22–25] is aimed to obtain simple rules, recommendations or expressions useful for the PID governor tuning in the plant predesign phase, but they do not include water elasticity effects. For this purpose Classic Control tools and techniques, (root locus plot, bode diagram,...) have been successfully applied.

In this paper, a methodology is presented to achieve a similar objective taking into account water elasticity effects. For this purpose, a simplified linearized model is proposed to define some practical tuning criteria for a PI governor by pole placement method [22]. The model is based in a lumped parameters approach [16,26] adjusted to match the penstock frequency response in the range of interest.

The controller performance is evaluated from the plant dynamic response obtained by simulation, using a detailed model which includes nonlinearities and distributed elasticity effects. The proposed PI adjustment criteria are tested in a real system implemented in a small island where the generation is provided by a wind farm and a hydropower plant [3,27]; the frequency is supposed to be controlled only by the hydropower plant.

Although modern wind generators could contribute to frequency regulation through pitch control, this contribution entails a cost: some wind energy will be lost [28]. So, in this paper no contribution to frequency regulation from the wind farm is assumed.

The paper is organized as follows. In Section 2 the hydro plant dynamic model is described and a preliminary assessment of elasticity effects is done using three reference power plants. In Section 3 the applicability of a reduced order model for stability analysis is discussed. In Section 4 two tuning criteria are formulated using the reduced order model and their performance is analysed. In Section 5 the obtained results are tested in a real hydropower plant: Gorona del Viento in El Hierro (Canary Islands). Finally, in Section 6, main conclusions of the paper are duly drawn.

2. Modelling

Assuming that a hydroelectric plant operates in an isolated system, which includes wind generation and resistive loads, the block diagram of its dynamic model is shown in Fig. 1.

The equations associated with each block are detailed below. All variables, coefficients and parameters which appear in the expressions are described in the Appendix 1. In particular, p_d represents the net demand to be supplied by the hydro plant.

2.1. Penstock

In order to consider the elasticity of water and conduit, the expression (1) is used [14].

$$\frac{\Delta H(s)}{\Delta Q(s)} = -\frac{T_w \frac{a_w}{L}\left(1 - e^{-2\frac{L}{a_w}s}\right)}{\left(1 + e^{-2\frac{L}{a_w}s}\right)} \quad \text{where} \quad T_w = \frac{L}{gF}\,\frac{Q_b}{H_b} \tag{1}$$

For the sake of accuracy the head losses, local (k_{loc}) and continuous ($r/2$), are included as shown in Fig. 2 [15]. The net head h, is obtained from the reservoir water level hc^0, considering the friction losses and the pressure waves contribution.

2.2. Turbine

The Equation (2) [15] gives the relationship between p.u. values of flow q, head h and nozzle opening z.

$$q = z\sqrt{h} \tag{2}$$

As is frequently the case in hydropower plants with long penstocks located in islands, Pelton turbines will be considered. The expression (3) used for p.u. shaft torque corresponds to ideal rated conditions, where the absolute fluid speed is twice the runner peripheral speed [29].

$$c = q\left(2\sqrt{h} - n\right) \tag{3}$$

The modelled power plant may have two or more identical units, which are supposed to work at the same operating point; thus a single equivalent turbine has been considered.

2.3. Generation − load

Equation (4) represents unit dynamics in the time range of interest, where only inertial effects are relevant [10,30].

$$c - c_d - k\Delta n = T_m \frac{dn}{dt} \tag{4}$$

As mentioned in the Introduction, the considered hydro power plant is connected to an isolated system with wind generation; then c_d represents the p.u. net load torque at reference frequency, $n_r = 1$ p.u. Input variable $p_d = c_d$ p.u. (see Fig. 1) is modified as a result of a variation in the loads connected to the system or a change in the energy supplied by the wind farm. Inertia parameter T_m refers only to the hydro plant as wind generators are supposed to be connected to the system through frequency converters. The parameter k accounts for the load sensitivity to frequency, as wind generation does not contribute to frequency regulation.

2.4. PI controller

A conventional proportional-integral (PI) controller processes the frequency error signal: $(n_r - n) - \sigma\Delta z$. Equation (5) gives the changes in the turbine nozzles due to the controller action.

$$\Delta z = \left[\frac{1}{\delta} + \frac{1}{\delta T_r}\int dt\right]\left[(n_r - n) - \sigma\Delta z\right]; \quad K_P = \frac{1}{\delta} \text{ and } K_I = \frac{1}{\delta T_r} \tag{5}$$

In the case considered, the frequency control is carried out only by the hydro plant; then, the permanent speed droop σ is set to zero and the frequency set-point n_r remains constant.

2.5. Example. Reference power plants

The importance of elasticity effects is assessed using three reference hydropower plants with different penstock lengths, the PI governor being tuned according to the recommendations given in Ref. [11] for an isolated plant without considering the elasticity of water and conduit. The main characteristics of the reference power plants are summarized in the Table 1.

As may be appreciated in the table, the three proposed reference plants differ substantially in the values of the Allievi parameter $\rho = a_w\, v/2\, gH$. In Ref. [12] the influence of the Allievi parameter on the stability of a hydro plant is studied, concluding that elasticity effects are important for $\rho < 1$. In Ref. [31] this limit is reduced to 0.75, warning that instability will appear when $\rho < 0.25$; in a

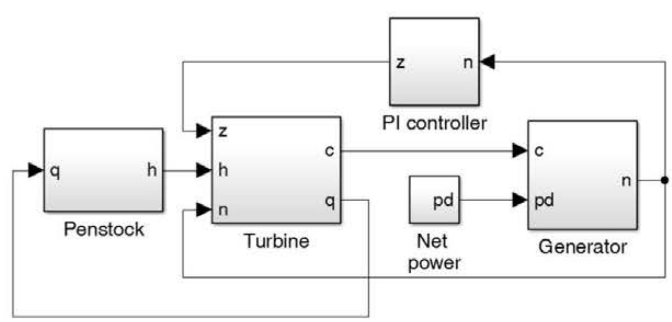

Fig. 1. Block diagram of the plant model.

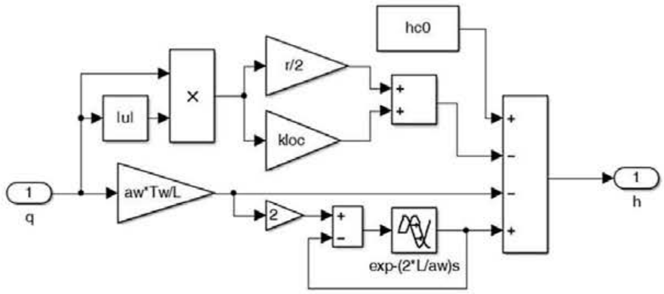

Fig. 2. Block diagram of penstock.

numerical example analysed in this reference results that for $\rho \approx 0.4$ the inelastic model underestimates significantly the speed deviation.

Fig. 3 represents the dynamic response of each power plant due to a 5% sudden reduction of the power demanded. The results obtained for each plant confirm the conclusions reported by the references cited above.

3. Reduced order model

For control design purposes in plants with long penstock, it is convenient to use a reduced order model including elasticity effects [5].

3.1. Lumped parameters approach

In last years some numerical hydro plant models including elasticity effects [16,17] have represented the penstock by several consecutive elements where the conduit properties: inertia, elasticity and friction are assigned proportionally to the segment length.

The "configuration" and "orientation" of the elements are chosen according to the upstream and downstream boundary conditions. In the case shown in Fig. 4 these boundary conditions are given by the head at both ends of the conduit.

The penstock dynamics is defined in per unit values by the expressions (6) and (7).

$$\frac{dq_{t,i}}{dt} = \frac{n_t}{T_W}\left(h_{i-1} - h_i - \left(\frac{r}{2} + k_{loc}\right) q_{t,i}|q_{t,i}|\right) \tag{6}$$

$$\frac{dh_i}{dt} = \frac{(n_t - 1)}{T_l}\left(q_{t,i} - q_{t,i+1}\right) \text{ with } T_l = \frac{T_e}{Z} \tag{7}$$

where $T_e = L/a_w$ is defined as the water "elastic" time and $Z = T_a/T_e$ is the penstock surge impedance (p.u.) [1]. In the scheme shown in Fig. 4 there are n_t series branches and $n_t - 1$ shunt branches.

Table 1
Reference power plants characteristics.

	Power plant 1	Power plant 2	Power plant 3
T_w	1.0 s	1.0 s	1.0 s
T_m	6.0 s	6.0 s	6.0 s
a_w	1000 m/s	1000 m/s	1000 m/s
L	250 m	1660 m	2500 m
$r/2 + k_{loc}$	0.030 p.u.	0.030 p.u.	0.030 p.u.
ρ	2.0	0.3	0.2
δ	0.3833	0.3833	0.3833
T_r	5.0 s	5.0 s	5.0 s

The number of segments obviously determines the order of the complete system. In Appendix 2 the step response of the subsystem penstock-turbine is obtained with lumped parameters models with one or ten segments and compared with that obtained with the continuous model. The results show that the number of elements must be high enough to cover the frequency range of the plant response.

3.1.1. One-segment model, Π scheme

The simplest model is a Π-shaped one segment model having one series branch and two shunt branches. Since the height at the upstream end of penstock can be considered as constant, a second order model will result. The expressions (8) and (9) represent penstocks dynamics in this case.

$$\frac{dq_t}{dt} = \frac{1}{T_W}\left(h_c - h - \left(\frac{r}{2} + k_{loc}\right) q_t|q_t|\right) \tag{8}$$

$$\frac{dh}{dt} = \frac{2}{T_l}(q_t - q) \tag{9}$$

In order to assess the applicability of this model, the frequency response of the penstock of reference power plant 2 has been determined using the continuous penstock model, the rigid water column penstock model (assuming $tanh(sL/a_w) \approx sL/a_w$) and the one-segment model approximation (8) and (9). The results are shown in Fig. 5; from this figure is clear that the rigid water column model can be used only when the response has a very low frequency range; even the frequency response of the one-segment model represented by Equations (8) and (9) shows some significant deviations with respect to the continuous model (1) in the range of frequencies observed in Fig. 3. Therefore, as in Refs. [13,32], some adjustments should be done in order to use the one-segment penstock model in stability analysis.

3.1.2. Adjusted one-segment model

Transforming the expressions (8) and (9) to the frequency domain and neglecting the friction terms, the resulting penstock transfer function can be written:

$$\frac{\Delta H(s)}{\Delta Q(s)} = -\frac{sT_W}{1 + s^2\frac{T_l' T_w}{2}} \tag{10}$$

where a modified parameter $T_l' = \beta T_l$ has been considered, introducing the correction factor β. The physical meaning of this coefficient can be understood as if in (9) the fraction of the conduit elasticity which corresponds to the downstream end of penstock were different than 1/2.

The value of the correction coefficient β is obtained by equating the frequency corresponding to the poles of the one-segment transfer function (10) with the first peak of the frequency response of continuous model (1). This frequency, neglecting losses, is $(\pi a_w)/2L$, then

$$\frac{1}{\sqrt{\frac{T_l' T_w}{2}}} = \frac{\pi a_w}{2L} \tag{11}$$

This results in $\beta = 8/\pi^2$, which is a constant value independent of penstock parameters. The frequency response of the adjusted one-segment model is also represented in Fig. 5 and shows a good concordance with the continuous model for frequencies up to the first peak. As the frequencies observed in Fig. 3 are within this range, an accurate enough response can be expected using this model.

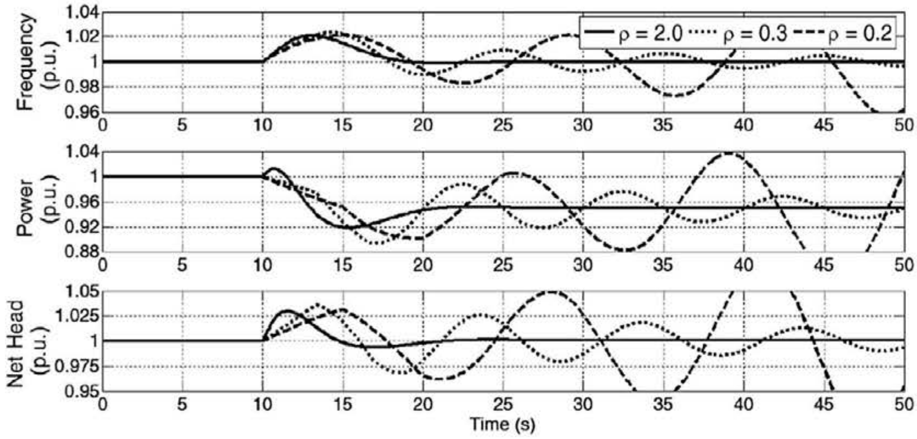

Fig. 3. Reference Power plants 1, 2 and 3 dynamic response, $\Delta p_d = -0.05$ p.u.

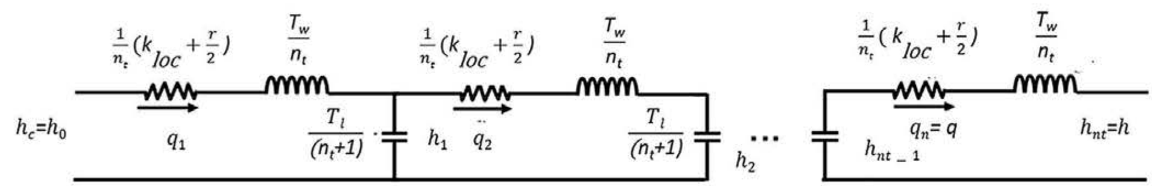

Fig. 4. Scheme of the penstock model.

To verify the adequacy of the adjusted one-segment model, the response of the complete plant model after a sudden reduction of 50% of the power demanded is simulated using the reference plant 2 data. In Fig. 6, the results obtained using the continuous model are compared with those obtained with the 10 segments and the adjusted one-segment models. Simulation results demonstrate that higher frequency modes do not appear in the response of the complete power plant model. Moreover, the response obtained with the adjusted one-segment model is fairly close to that obtained with the continuous model; therefore, the penstock adjusted one-segment model is considered as adequate.

3.2. Linearization

Some of the components described above are represented by nonlinear expressions and, so, not suitable for synthesizing the controller using linear methods. Therefore, a linearized model is developed for small perturbation analysis in the neighbourhood of an initial equilibrium operating point.

The equations that characterize the hydro power plant are (2), (3), (4), (5), (8) and (9); nonlinearities appear in the turbine Equations (2) and (3), and in the inertial penstock Equation (8).

3.3. Turbine

The linearized model of a hydraulic turbine can be written as follows:

$$\Delta q = b_{11}\Delta h + b_{12}\Delta n + b_{13}\Delta z \quad \Delta c = b_{21}\Delta h + b_{22}\Delta n + b_{23}\Delta z \tag{12}$$

The coefficients b_{1i} are the partial derivatives of the water flow (2) with respect to net head, speed and nozzle position; the coefficients b_{2i} are the partial derivatives of the torque (3) with respect to the same variables. Both groups of coefficients are expressed in (13).

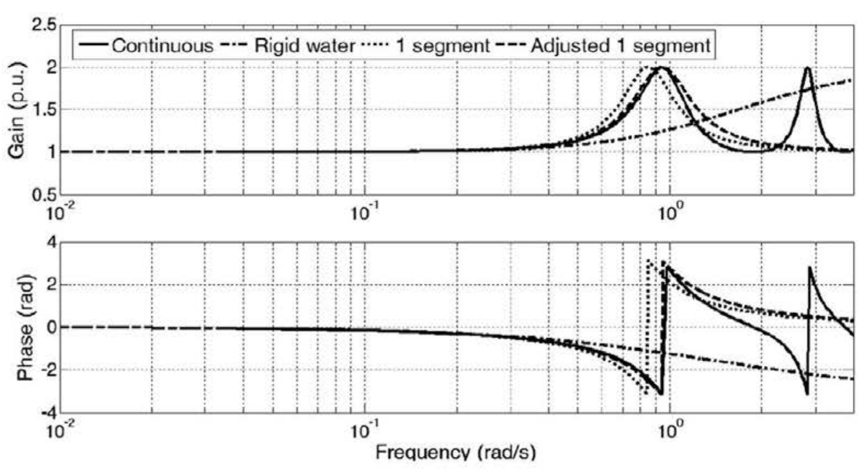

Fig. 5. Frequency response of penstock-turbine models, reference power plant 2.

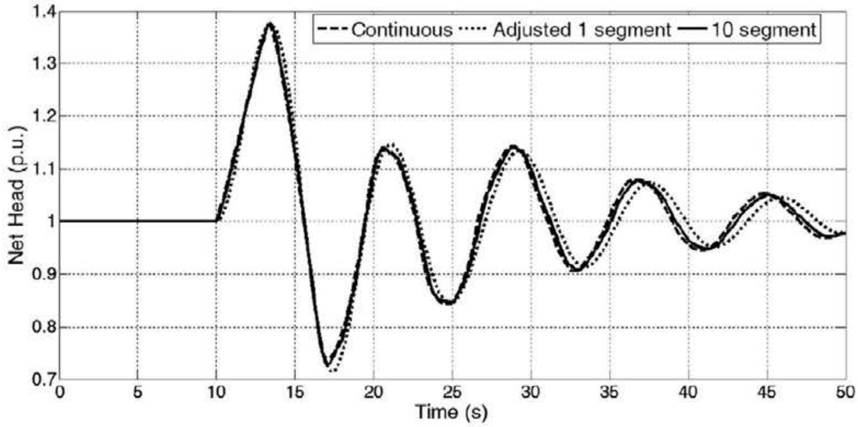

Fig. 6. Reference power plant 2 response. $\Delta p_d = -0.5$ p.u.

$$b_{11} = \frac{\partial q}{\partial h}\bigg|_{(h,n,z)_0} = \frac{z_0}{2\sqrt{h_0}} \quad b_{21} = \frac{\partial c}{\partial h}\bigg|_{(h,n,z)_0} = 2z_0 - \frac{z_0 n_o}{2\sqrt{h_0}}$$
$$b_{12} = \frac{\partial q}{\partial n}\bigg|_{(h,n,z)_0} = 0 \qquad b_{22} = \frac{\partial c}{\partial n}\bigg|_{(h,n,z)_0} = -z_0\sqrt{h_0}$$
$$b_{13} = \frac{\partial q}{\partial z}\bigg|_{(h,n,z)_0} = \sqrt{h_0} \quad b_{23} = \frac{\partial c}{\partial z}\bigg|_{(h,n,z)_0} = 2z_0 - n_0\sqrt{h_0} \tag{13}$$

$$A = \begin{pmatrix} -\frac{2b_{11}}{T'_l} & \frac{2}{T'_l} & -\frac{2b_{13}}{T'_l} & -\frac{2b_{12}}{T'_l} \\ -\frac{1}{T_w} & -2\frac{\left(\frac{r}{2}+k_{loc}\right)q^0}{T_w} & 0 & 0 \\ -\frac{b_{21}}{\delta T_m} & 0 & -\frac{b_{23}}{\delta T_m} & -\frac{b_{22}-k+\frac{T_m}{T_r}}{\delta T_m} \\ \frac{b_{21}}{T_m} & 0 & \frac{b_{23}}{T_m} & \frac{b_{22}-k}{T_m} \end{pmatrix} \tag{16}$$

$$B = \begin{pmatrix} 0 \\ 0 \\ \frac{1}{\delta T_m} \\ -\frac{1}{T_m} \end{pmatrix} \quad x(t) = \begin{pmatrix} \Delta h \\ \Delta q \\ \Delta z \\ \Delta n \end{pmatrix} \quad u(t) = (\Delta c_d)$$

3.4. Penstock

Linearizing the friction losses term in the penstock Equation (8) results in:

$$\frac{d\Delta q_t}{dt} = \frac{1}{T_w}\left(-\Delta h - 2\left(\frac{r}{2}+k_{loc}\right)q_t^0\Delta q_t\right) \tag{14}$$

3.5. State space formulation

Finally, the plant model results in a 4th order linear invariant dynamic system. The state equations written in canonical form are:

$$\frac{dx(t)}{dt} = \boldsymbol{A}x(t) + \boldsymbol{B}u(t) \quad \text{Where A and B matrixes are} \tag{15}$$

4. Tuning criteria

The methodology followed in the present paper is based in the pole placement technique [21,28,30]. Poles position in the complex plane is closely related to the power plant response. System poles can be determined as the roots of the characteristic polynomial associated to the dynamic matrix A (16) and their position depends of governor tuning. Thus, the PI gains should be selected so that the poles position gives rise to a dynamic response whose characteristics are as close as possible to the specifications (rise time, overshoot, settling time, etc.) [21].

To obtain results that could be easily applied to different power plants without arduous mathematical calculations some simplifications are considered in matrix A:

- The power plant is supposed to work in rated conditions. The base values of the model correspond to the rated operation point. Therefore h^0, q^0 and z^0 and are equal to 1.0.
- Friction losses are neglected
- The loads connected to the power plant are resistive and inertialess. This assumption is usual in the case of power plants connected to isolated systems [33].

The resulting coefficients b_{ij}, k and $r/2 + k_{loc}$ are shown in Table 2.

The characteristic polynomial is obtained from the dynamic matrix, (16), using the parameters of Table 2; the result is expressed by Equation (17).

$$x^4 + \left(\frac{\delta T_m + T_l'}{\delta T_m T_l'}\right)x^3 + \left(\frac{-2T_wT_r + T_wT_l' + 2\delta T_m T_r}{T_l' T_r T_w \delta T_m}\right)x^2 + \left(\frac{2T_r - 2T_w}{T_l' T_r T_w \delta T_m}\right)x + \frac{2}{T_l' T_r T_w \delta T_m} = 0 \tag{17}$$

The pole's real part has a direct relation to the settle time. The tuning philosophy of [29] is based on avoiding the slow pole and equating the real part of the poles near the imaginary axis.

A similar strategy is followed in Ref. [30] but applied to water level control. In this case there was other priority: reducing the wicket gates movements. So, one pair of eigen values was placed on the real axis. This approach minimizes the effort made by the servo which acts on the turbine wicket gates. The resulting excessive overshoot is not a problem because the tolerance to water level variations is larger than to frequency variations.

In the next sections two tuning criteria are proposed:

- Double Real Pole (DRP). The four poles have the same real part but one pair of poles is on the real axis. This strategy is taken from Ref. [30], where it is applied to water level control.
- Double Complex Pole (DCP). Two pairs of conjugate identical poles.

4.1. *Double real pole criterion (DRP)*

The four close-loop poles are of the form $\{a, a, a \pm jb\}$ [30]. Therefore, the characteristic polynomial can be expressed as follows (18).

$$(x-a)(x-a)(x-(a+jb))(x-(a-jb)) = 0 \tag{18}$$

The expression (17) is identified to (18) and the result is a fourth order equation system (19). The four unknown variables are a, b, δ and T_r.

Table 2
Tuning assumed values.

b_{11}	0.5	b_{12}	0.0	b_{13}	1.0
b_{21}	1.5	b_{22}	−1.0	b_{23}	1.0
$r/2+k_{loc}$	0.0	k	−1.0		

$$\frac{\delta T_m + T_l'}{\delta T_m T_l'} = -4a \quad \frac{-2T_wT_r + T_wT_l' + 2\delta T_m T_r}{T_l' T_r T_w \delta T_m} = 6a^2 + b^2$$
$$\frac{+2T_r - 2T_w}{T_l' T_r T_w \delta T_m} = -4a^3 - 2ab^2 \quad \frac{2}{T_l' T_r T_w \delta T_m} = a^4 + a^2b^2 \tag{19}$$

The expressions that represent the solution of the nonlinear system are quite complex. So, in order to simplify the presentation of the results, a graphical solution is shown in Fig. 7. Knowing the water time constant T_w and the elastic wave time L/a_w of the penstock it is possible to obtain the reset time T_r and the product of temporary droop and mechanical time $\delta \cdot T_m$. This tuning criterion is thought to be applied in the context of long penstocks, so Allievi parameter is lower than 0.5.

The Double Real Pole criterion is applied to the reference power plant 2 ($T_w = 1.0$ s, $L/a_w = 1.66$ s and $T_m = 6$ s). The resulting pair of gains is included in Table 3.

The same simulation done previously, sudden loss of 5% net demanded power in reference power plant 2 adjusted with a classic criterion [11] (Fig. 3), is done now again with the controller adjusted with DRP criterion. Simulation graphical results are shown in Fig. 9. As it can be appreciated in this figure, the proposed adjustment improves the results obtained with classic recommendations. Table 4 contains response characteristics with the purpose of evaluating and comparing the quality of the responses. The settling time is considerably reduced by DRP but the overshoot and consequently the quadratic and absolute errors are higher. It is worth to highlight that DRP has been taken from water level control where reducing the overshoot was not a priority.

4.2. *Double complex pole criteria (DCP)*

DCP criterion maintains the philosophy of equal real part in each pole. Second condition is to equate absolute value of the four imaginary parts. In this way, one oscillation would not prevail over the other. The expected result is to continue reducing the settling time and to decrease the overshoot in the frequency response.

The four close-loop poles are of the form, $\{a \pm jb, a \pm jb\}$ and the characteristic polynomial expression is (20).

$$(x-(a+jb))^2(x-(a-jb))^2 = 0 \tag{20}$$

In this case the equation system, that is the result of identifying the two expressions of characteristic polynomial, (17) and (20), is:

$$\frac{\delta T_m + T_l'}{\delta T_m T_l'} = -4a \quad \frac{-2T_wT_r + T_wT_l' + 2\delta T_m T_r}{T_l' T_r T_w \delta T_m} = 6a^2 + 2b^2$$
$$\frac{2T_r - 2T_w}{T_l' T_r T_w \delta T_m} = -4a^3 - 4ab^2 \quad \frac{2}{T_l' T_r T_w \delta T_m} = a^4 + 2a^2b^2 + b^4 \tag{21}$$

A parametric solution is presented in the Fig. 8 and the particular values of PI gains, corresponding to the reference power plant 2, are shown in Table 3.

Simulations previously done in reference power plant 2, with classic and DRP criteria are completed now with the controller tuned using DCP criterion. Simulation graphical results are summarized in Fig. 9 and Table 4 contains the main response characteristics.

In this case, the poles were not forced to be located over the real axis. Therefore, the response has more oscillations than the DRP response. Nevertheless, this oscillation is damped quicker and the settling time is the lowest. The frequency overshoot and the mean absolute error $\overline{\sum|\boldsymbol{\varepsilon_n}|}$ are similar than classic's. Only the mean

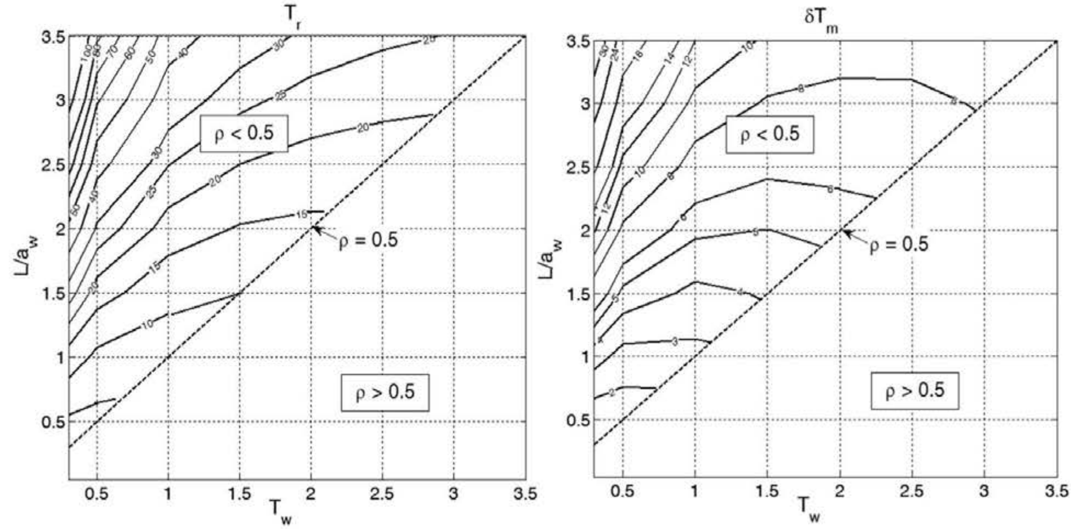

Fig. 7. PI Tuning curves, double real pole criteria.

Table 3
PI Gains for reference power plant 2.

	Double real pole	Double complex pole	Classic
δ	0.6942	0.5251	0.3833
T_r (s)	13.3064	3.7939	5.0000

square error $\overline{\sum e_n^2}$ is slightly higher than the error obtained with the classic criterion.

5. Case study

Recommendations extracted from this study are applied to the governor of Gorona del Viento Hydropower Plant. This plant is located in El Hierro, an island belonging to Canary Islands archipelago and declared a Biosphere Reserve by UNESCO. The island aims to become 100% carbon dioxide emissions free [3]. The energy demand is supplied by a wind farm and the hydro power plant mentioned above. The plant can operate also in pumping mode and so, the excess of available wind energy is stored in the upper reservoir.

In this context it can be assumed isolated operation hypothesis: variations of the net power demanded, due either to a variation in load demand or in the wind generation, are balanced only by the hydro power plant.

The hydro power plant data used in the model have been taken from Ref. [27]. They are summarized in Table 5.

Presently Gorona del Viento power plant never works with all units operating simultaneously, because maximum power demanded in the island do not usually exceed 7 MW. In valley hours the demanded power is around 4 MW. Therefore, as an average case, it is assumed the power plant operates with two units at full load. Then, the rated and base flow are set in the value 1.0 m^3/s. This hypothesis affects the water losses in the penstock and the water starting time T_W. The Allievi parameter value is one-half of the value with all the units operating; so this assumption is more exigent for the tuning criteria. The numerical values of these parameters are shown in Table 6.

Table 7 contains the numerical values of PI gains tuned according to the DRP, DCP and classic criteria. The eigen values

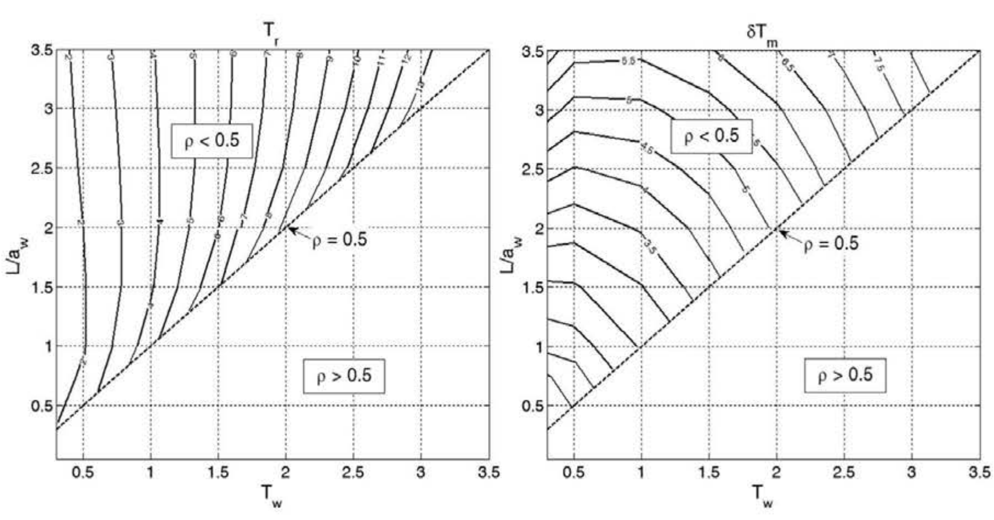

Fig. 8. PI Tuning curves, double complex pole criteria.

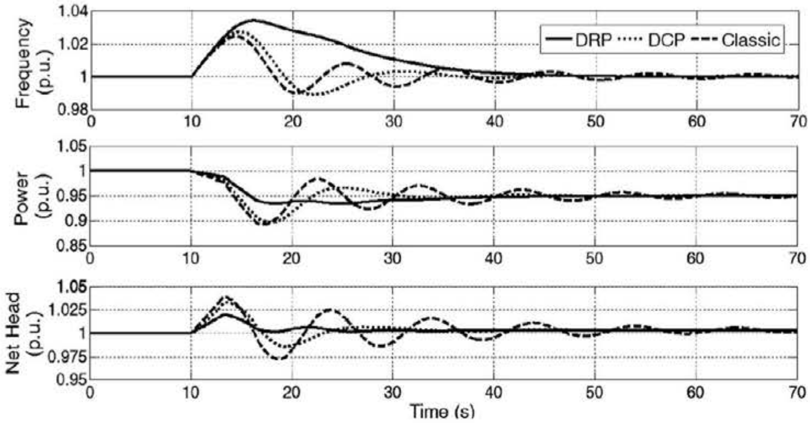

Fig. 9. Hydro plant dynamic response. DCP, DRP and Classic Criteria. $\Delta p_d = -0.05$ p.u. First 70 s.

Table 4
Response quality parameters. Reference power plant 2. $\Delta p_d = -0.05$ p.u. Simulation time 200 s.

Criteria	$\overline{\sum \varepsilon_n^2}$	$\overline{\sum \lvert\varepsilon_n\rvert}$	$max\,\lvert\varepsilon_n\rvert$	$T_{2\%}$ (s)
Classic	$1.5360 \cdot 10^{-5}$	$1.3904 \cdot 10^{-3}$	0.02436	83.1
Double Real Pole	$6.1043 \cdot 10^{-5}$	$2.6632 \cdot 10^{-3}$	0.03402	37.1
Double Complex Pole	$1.9399 \cdot 10^{-5}$	$1.2167 \cdot 10^{-3}$	0.02714	35.0

obtained from the fourth order power plant model, tuned with classic criterion, are also shown in this table. One pair of poles has positive real part so the system response in this case will be unstable and no simulations will be carried out with this governor configuration.

One of the main requirements for this hydro power plant is maintaining the frequency within the power quality limits according to regulation [34]. The ranges of frequency variations are for non-interconnected supply systems: 50 Hz ± 2% for 95% and 50 Hz ± 15% for 100% of a week. Two different simulations are carried out. On the one hand, an event that may occur frequently is modelled (normal operating conditions), and in the other hand an unlikely event is simulated (abnormal conditions). Both simulations are carried out with the power plant controller tuned with the two criteria presented in previous section.

5.1. Normal operating conditions

A common event in hydropower plants operating in isolated systems with high wind penetration is produced by wind fluctuations giving rise to variations in the wind generated power [35]. As an example, an increase in the wind speed is supposed causing a linear increase of the power produced by wind turbines. The net power p_d decreases and the hydro power plant is asked to reduce its production in order to maintain the system frequency. The required power variation is −0.25 p.u in 60 s.

Table 5
Gorona del Viento Power plant ratings.

Generating unit	Rated Power	2.830 MW
	Rated flow	0.50 m^3/s
	Number of units	4
	Rated speed	1000 r.p.m.
	Mechanical starting time (T_m)	6 s
	Gross head	670 m
Penstock	Length	2577 m
	Diameter	1 m
	Darcy – Weisbach friction loss coefficient	0.015
	Wave speed (a_w)	1193 m/s
	Relation L/a_w	2.16 s

Table 6
2 units operating.

ΔH	4.75 m
T_w	0.5028 s
ρ	0.1164

Simulations results are shown in Fig. 10. It can be observed that the response with the controller tuned with DRP criterion is not strong enough, so the frequency overshoot exceeds the maximum allowed values (±2%). In the case of the DCP criterion, frequency deviation fulfils the desired requirements.

5.2. Abnormal conditions

A sudden and unexpected disconnection of one wind generator (2.3 MW) is considered as an abnormal situation in the power plant operation. It is assumed that the wind generation do not participate in frequency regulation; thus the hydro plant increases the generated power to compensate the generation loss and recover the frequency.

Fig. 11 contains graphical results of the described simulation. DRP criterion reduces the oscillations in the frequency or power at expenses of the excessive frequency overshoot. Nevertheless, when the controller is tuned with DCP criterion the frequency is maintained within the established limits (±2%).

Although, unfortunately, these results cannot be compared at the present time with experimental data, it seems reasonable to expect a fairly good agreement, because a similar model has been used in Ref. [36] for Dinorwig power plant, where the simulation results reproduce with enough accuracy field measurements.

Table 7
Gorona del Viento power plant PI tuned gains.

	Double real pole	Double complex pole	Classic	
			Gains	Eingenvalues (Adjusted 1 segment model)
δ	1.4325	0.5713	0.1990	0.0724 ± 0.6059j
T_r (s)	32.8405	2.0511	2.6390	−0.5719 ± 0.3429j

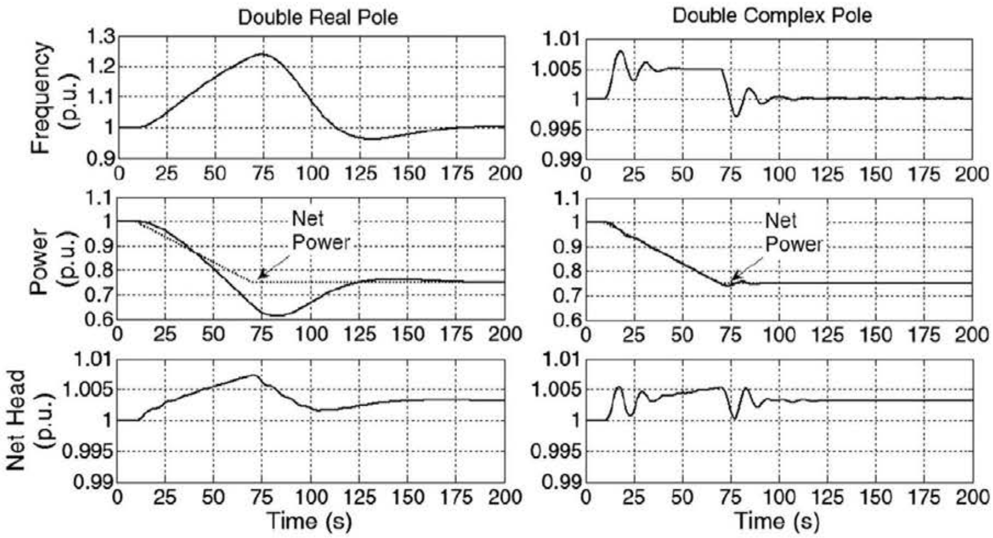

Fig. 10. Dynamic response of the central with $\Delta p_d = -0.25$ p.u in 60 s.

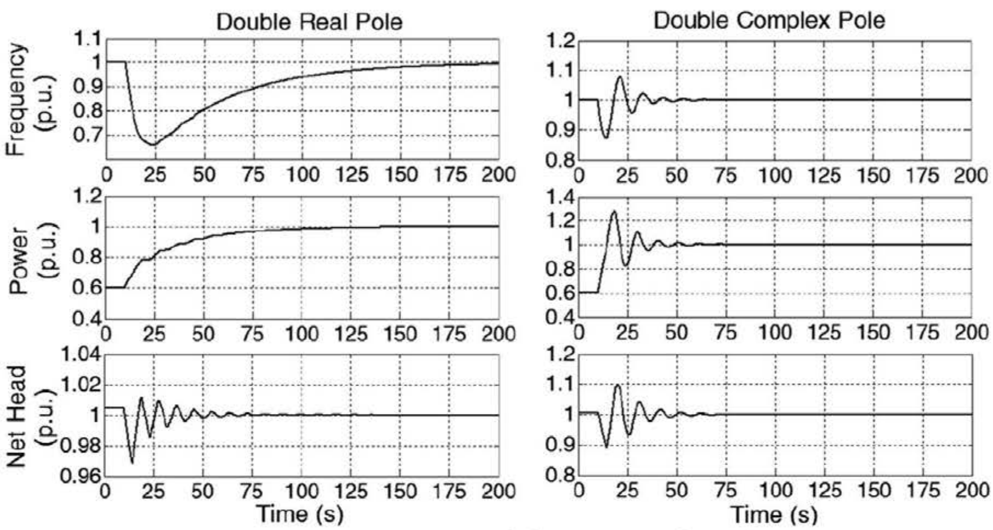

Fig. 11. Dynamic response of the central with $\Delta p_d = 0.40$ p.u.

6. Conclusions

In this paper a model of a hydro power plant with long penstock connected to an isolated system is described. This configuration frequently corresponds to pumped storage power plants coexisting with wind farms in small islands. It has been found that penstock length may affect governor PI gains settings, especially when Allievi parameter is lower than 0.5. Classical tuning criteria do not take into account this issue; so new recommendations are formulated to solve this matter.

A reduced order model based in lumped parameters approach is proposed for stability analysis. The adequacy of a one-segment model adjusted in frequency domain to represent penstock dynamics has been verified. The simulations show that high frequencies do not appear in the power plant response.

Using the reduced order model, two new tuning criteria, based on pole placement method, have been formulated; one of them (DRP) was previously applied in a water level control context. Both are compared to the known classic criteria using a reference power plant with long penstock ($\rho = 0.30$). Results from simulations reveal that new criteria notably improve response quality.

Finally, formulated criteria were applied to Gorona del Viento hydro power plant, located in El Hierro island, where there is also wind generation. Several situations (normal and abnormal) have been modeled with the governor tuned according to the two proposed criteria; classic criterion leaded to instability. The best performance was obtained when the governor gains were tuned using the Double Complex Pole (DCP) criterion. Since the DRP criterion was developed for water level control, the DCP criterion is expected to perform better than DRP in load frequency control, whatever the power plant parameters.

Acknowledgements

The work presented in the paper has been partially funded by the Spanish Ministry of Economy and Competitiveness Ref. ENE2012-32207 under the project "Optimal operation and control of pumped-storage hydropower plants" of The National Scientific

Research, Development and Technological Innovation Plan 2008–2011 (Ref. ENE2012-32207).

Nomenclature

a	Real part of the solutions of the characteristic polynomial
a_w	Wave speed (m/s)
b	Complex part of the solutions of the characteristic polynomial
b_{ij}	Turbine linear coefficients (p.u.)
c	Turbine mechanical torque (p.u.)
c_d	Net load torque at rated frequency (p.u.)
F	Penstock section (m^2)
g	Gravity acceleration (m/s^2)
h	Net head (p.u.)
h^0	Initial net head (p.u.)
H	Net head (m)
$H(s)$	Net head in frequency domain (p.u.)
H_b	Base head (m)
h_c	Reservoir water level (p.u.) $\approx h_c^0$ (variations along the time of the study are neglected)
h_c^0	Initial reservoir water level (p.u.)
h_i	Head at the end of the i-th Π element of the penstock (p.u.)
j	$\sqrt{-1}$
K_P	Proportional gain in PI governor
K_I	Integral gain in PI governor
k	Load self-regulation coefficient
k_{loc}	Localized head losses coefficient (p.u.)
L	Penstock length (m)
n	Frequency (p.u.)
n_r	Reference frequency (p.u.)
n_t	Number of segments in which the penstock is divided
p_d	Net demanded power in system (p.u.)
$Q(s)$	Flow through the turbine in frequency domain (p.u.)
Q_b	Base flow (m^3/s)
q	Flow through the turbine (p.u.)
q^0	Initial flow through the turbine (p.u.)
q_t	Flow at the penstock (p.u.)
q_t^0	Initial flow at the penstock (p.u.)
$q_{t,i}$	Flow at the end of the i-th Π element of the penstock (p.u.)
$r/2$	Continuous head loses coefficient (p.u.)
$T_{2\%}$	Settling time (s)
T_e	L/a_w, water elastic time (s)
T_I	T_e/Z (s)
T'_I	βT_I (s)
T_m	Mechanical starting time (s)
T_r	Dashpot time constant (s)
T_w	Penstock water starting time (s)
v	Water speed in the penstock (m/s)
z	Nozzle opening (p.u.)
Z	T_a/T_e, penstock surge impedance (p.u.)
z^0	Initial nozzle opening (p.u.)
β	Correction coefficient
δ	Temporary speed droop
σ	Permanent speed droop
ρ	Allievi parameter
$max\left\|\varepsilon_n\right\|$	frequency overshoot (p.u.)
$\overline{\sum\left\|\varepsilon_n\right\|}$	Frequency mean absolute error (p.u.)
$\overline{\sum\varepsilon_n^2}$	Frequency mean square error (p.u.)

Turbine-penstock dynamic response

In order to make clear the nature of the lumped parameters approach, the subsystem penstock-turbine has been isolated and a sudden reduction of 50% of the turbine nozzles opening was simulated. The parameters of the reference power plant 2 (Table 1) have been used. The continuous model response is compared to that obtained with the adjusted one-segment model and also with the one obtained with a ten-segment lumped parameters model.

Simulation results show that adjusted one-segment model is able to reproduce the fundamental frequency but ignores higher frequencies. Logically, the ten-segment model response is more accurate and covers a higher frequency range.

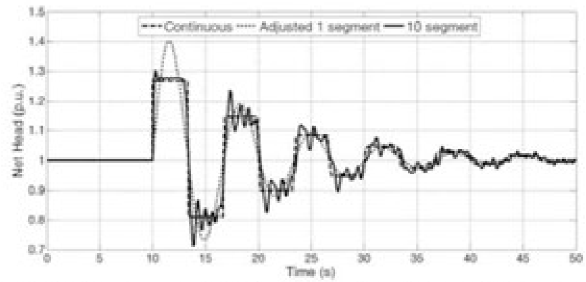

Fig. A2-1. Reference power plant 2, isolated system Penstock-Turbine response. $\Delta z = -0.5$ p.u.

Then, the number of elements of a lumped parameters model should be selected so as to include the modes within the range of frequencies involved in the plant response.

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